BC hydro

Value of Electricity

Resource Planning
Corporate and Environmental Affairs

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B.C. Hydro

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SUMMARY

B.C. Hydro strives to optimize the supply, marketing and management of existing and planned resources on a consistent basis. To evaluate investments in projects where the capacity and energy capability of the project changes as a function of the investment, the value of capacity and energy must be established. In this document the **sum of the values of firm capacity and firm energy** is referred to as the **value of electricity.**

The purpose of this report is to calculate the value of electricity which is defined, depending on the time frame, as either the change in costs associated with the change in demand for electricity, or as the market value of the electricity. This document is updated annually.

B.C. Hydro's 1989 Resource Plan identifies the requirement for the next resource addition in the year 1998. Until that time electrical energy will be supplied either from existing or committed resources or from purchases. Therefore, prior to the year 2000, the value of electricity is based on incremental changes in use of existing and committed resources and, in times of surpluses, on the marketing opportunities for B.C. Hydro's electric energy. The value of electricity increases year by year as the surplus is depleted and exceeds the unit cost of the Keenleyside project around the year 1998 indicating that in that year it would become economical to bring it into service.

To supply the growing load after the year 1999 additional generation resources will be required. Therefore, beyond the year 2000, the value of electricity is based on the cost of new generation additions and is estimated at 5 c/kW.h. This value represents the projected future market value of electricity and is based on the **market opportunity cost** of the estimated capital needed for new generation projects currently considered for development by B.C. Hydro. It is computed as a weighted average unit cost of the new projects evaluated at a discount rate of 8 percent.

The current values of electricity and its components, firm capacity and firm energy and values for secondary energy, expressed in 1989 dollars, are:

	MARGINAL VALUE			
	Electricity (¢/kW.h)	Firm Capacity $/kW/a	Firm Energy (¢/kW.h)	Secondary Energy (¢/kW.h)
1989/90	1.8	6.0	1.7	1.1
1990/91	1.8	6.0	1.7	1.1
1991/92	1.8	6.0	1.7	1.1
1992/93	1.9	6.0	1.8	1.1
1993/94	2.0	6.0	1.9	1.1
1994/95	2.3	6.0	2.2	1.1
1995/96	2.2	6.0	2.1	1.1
1996/97	2.8	6.0	2.7	1.3
1997/98	3.4	6.0	3.3	1.5
1998/99	4.2	6.0	4.1	1.7
1999/00	4.9	24.4	4.4	1.9
2000/01 and on	5.0	24.4	4.5	2.0

An estimate of the value of electricity is required for evaluation of new projects or purchases, for evaluation of modifications to the existing generation or transmission facilities or for evaluation of conservation programs.

Benefits associated with a particular project would be computed year by year for each year that the program would be in effect, using the values for energy and capacity provided in the table on the previous page. Similarly the costs would be computed for each year. Comparison of costs and benefits would be then done using a present worth method.

Appendix II of the report provides an actual example that demonstrates how the value of electricity might be used to evaluate merits of a design change to a generation project.

1.0 INTRODUCTION

1.1 Purpose

The Resource Planning Department annually revises its estimates of incremental values for capacity and for firm and secondary energy. These values are based on cost estimates of projects comprising B.C. Hydro's inventory of future generation developments in British Columbia and on the assessment of the market opportunity costs of either short term sales or long term purchase contracts. They are needed for evaluation of new projects, for evaluation of modifications to existing facilities or for evaluation of energy purchases or conservation programs.

In this document the **sum of the values of firm capacity and firm energy** is referred to as the **value of electricity.**

This report estimates the value of electricity for use during the 1989/90 fiscal year. The value of electricity is based either on an evaluation of avoided costs, or on market opportunity costs, depending on which one is expected to prevail. All costs are expressed in 1989 dollars.

Cost estimates of specific project arrangements selected from B.C. Hydro's current inventory are based on information provided to Resource Planning, most recently in October 1988, by B.C. Hydro's System Development Group and were then inflated to 1989 dollars using a 5% inflation factor.

1.2 Report Structure

Section 2 of this report discusses assumptions made regarding discount rates and taxes. It is followed by a section that describes the methodology used to derive short and long-term values of firm and secondary energy, and firm capacity.

Appendix I provides estimated long term unit costs of future generation projects that B.C. Hydro carries in its inventory. This Appendix also provides a detailed description of the methodology used to derive unit costs.

Appendix II provides an example that demonstrates how the value of electricity might be used to evaluate the merits of a design change to a generation project.

A glossary of frequently used terms is provided at the end of the report.

2.0 DISCUSSION

The value of electricity is frequently used to perform cost-benefit analysis and project optimization. For such studies sensitivity analysis is routinely done for a range of discount rates and with and without taxes. A brief discussion on the two topics is provided below.

2.1 The Discount Rate

The discount rate is used to convert revenues and expenditures occurring in different periods to a common present value basis. It is critical in comparing projects and in determining electricity costs, investment returns and the value of foregone alternatives. The appropriate discount rate can vary depending on the purpose of the analysis.

- A 4-5% real discount rate is applicable when assessing environmental values, value of foregone opportunities to future generations and future energy consumption.

- A 6% real discount rate represents the current cost of long term provincial borrowing, and should be the minimum rate achieved on new investment by B.C. Hydro if it is to avoid financial losses. This rate does not take account of project-specific risk.

- A 7-8% real discount rate reflects the average pre-tax return to public and private investment in Canada and trade-offs between savings and consumption, and should be used to measure benefits and costs to the economy as whole.

While the discount rate is an important parameter in analyzing financial aspects of alternatives, other issues such as social and environmental ones may have an overriding effect in making long term commitments. For example, when optimizing hydroelectric or transmission projects, to take into account the long term benefits that these projects provide to future generations a discount rate of 5 percent should be used. However, when comparing the projects or when performing a cost benefit analysis an 8 percent discount rate should be used with sensitivity analysis done at a 6 percent discount rate.

2.2 Taxes

B.C. Hydro pays water rental fees, grants and school taxes to provincial and municipal governments. From the overall Provincial perspective, taxes can be considered as a transfer of money from B.C. Hydro to the Province and are not a cost in an economic sense. However, taxes are a real cost from B.C. Hydro's financial perspective and therefore should be included in all cost-benefit calculations.

3.0 MARGINAL VALUE OF ELECTRICITY

The marginal value of electricity can be measured in many different ways. For example, it may be set equal to the current selling price of electricity or it could be determined from the price that people are willing to pay for the commodity. B.C. Hydro has chosen to base its determination of the long term marginal value of electricity on the cost of obtaining electricity from the lowest cost alternative source, (taking into account government directives on independent power producers), thus equating the marginal value to the marginal cost of electricity. In the short term the value of electricity is based more on the market opportunity cost.

3.1 Marginal Value of Electricity in the Short Term

In the short-term, when the generating capacity is essentially fixed, the marginal value of electricity is determined from the cost of obtaining additional capacity or energy from the existing system. Depending on the current firm energy surplus and streamflow conditions this increased demand would result in reduced spill, increased hydro generation, increased Burrard generation, increased purchases or reduced exports. The value of electricity will increase as domestic load grows.

The value of electricity in the short term is set by calculating the incremental and decremental production costs of 1000 GW.h/a of additional energy each year up to the in-service date of the next new plant in the 1989 Resource Plan (i.e. Keenleyside in 1998).

To establish the value of electricity in the short term the following procedure was followed:

1. A base system consisting of all existing plants was established. The expected annual system operation costs, which included water rental fees, fuel costs for Burrard and the cost of purchased energy, less estimated export sales were computed for each year of the study for 45 streamflow conditions.

2. Costs of system operations were then computed for two alternative systems: one where loads were increased by a 1000 GW.h/a and the other where loads were decreased by a 1000 GW.h/a.

3. The marginal values of energy for each year was then computed as the difference between the estimated system operating costs for the base case and for each of the alternative cases, divided by the difference in load. The two sets were then averaged.

4. During fiscal years 1989/90 and 1990/91, the marginal values of electricity have been estimated by B.C. Hydro's Operations Control Department taking into account the current reservoir elevations and near-term marketing opportunities.

The resulting values of electricity and its component firm capacity and firm energy as well as values for secondary energy are summarized below:

	MARGINAL VALUE			
	Electricity (¢/kW.h)	Firm Capacity $/kW/a	Firm Energy (¢/kW.h)	Secondary Energy (¢/kW.h)
1989/90	1.8	6.0	1.7	1.1
1990/91	1.8	6.0	1.7	1.1
1991/92	1.8	6.0	1.7	1.1
1992/93	1.9	6.0	1.8	1.1
1993/94	2.0	6.0	1.9	1.1
1994/95	2.3	6.0	2.2	1.1
1995/96	2.2	6.0	2.1	1.1
1996/97	2.8	6.0	2.7	1.3
1997/98	3.4	6.0	3.3	1.5
1998/99	4.2	6.0	4.1	1.7
1999/00	4.9	24.4	4.4	1.9

The above results to the year 1998 are based on incremental changes on existing resources and on the assumption that B.C. Hydro will purchase 2500 GW.h of firm energy from Alcan starting in 1995. They represent expected values of firm energy used to reduce the need for Burrard and other energy resources during combinations of high load growth or low streamflows, and to increase possible export sales during conditions of lower load growth or normal streamflows. As the surplus is depleted the short term value of electricity increases and approaches the unit cost of the Keenleyside project around the year 1998 indicating that it would be economically beneficial to bring that project into service. Keenleyside is the least costly project in B.C. Hydro's inventory of potential generation developments.

In the short-term the value of additional capacity is estimated at $6/kW/a and is based on recent marketing opportunities for B.C. Hydro's surplus capacity. Capacity export prices in the United States could be as high as $50/kW/a in the long term, but such sales have not yet been negotiated.

The short-term value of electricity is used to evaluate the benefits of project modifications to the in-service date of the next major project. It is also used to evaluate changes in energy production capability such as taking a generating unit out of service or the short term cost of supplying an additional block of industrial load.

3.2 Value of Electricity in the Long Term

In the long term, beyond the year 2000, the value of electricity is estimated at 5 c/kW.h. This value represents the projected future market value of

electricity and is based on the **market opportunity cost** of the estimated capital needed for new generation projects currently considered for development by B.C. Hydro. The value of electricity is a single value of capacity and energy and is computed as weighted average unit cost of the following projects: Keenleyside, Site C, Murphy Creek and all the remaining Lower Columbia River Projects. Unit costs were computed using an 8 percent discount rate.

The value of electricity, its components firm energy and firm capacity and the value of secondary energy is provided in Table 1.

Figure 1 provides a graphic representation of how the value of electricity varies over time.

a. Dependable Capacity

Based on the 1988/89 Probable Load Forecast, the existing B.C. Hydro facilities would provide surplus peak generating capacity until 1999.

The least expensive additional peaking capacity could be provided by adding units 5 and 6 at Mica and units 5 and 6 at Revelstoke. Therefore, the value of capacity has been determined from average present value costs of Mica and Revelstoke unit additions in the year 1999 and is estimated at $24.4/kW/a.

Assuming a capacity factor of 0.58[1] each kilowatt of capacity added would generate 5081 kW.h/a. A capacity value of $24.4/kW/a is therefore equivalent to an energy value of 0.5 c/kW.h.

b. Incremental Value of Firm Energy

As previously defined the long-term value of electricity is the sum of two components: the value of firm energy and the value of dependable capacity. The value of firm energy is calculated by subtracting the value of dependable capacity from the value of electricity. The incremental value of firm energy is therefore estimated at 4.5 c/kW.h.

c. Incremental Value of Secondary Energy

Secondary energy, when available, allows B.C. Hydro to reduce the need for energy purchases or expensive fossil generation and to increase exports.

To estimate the value of secondary energy the following procedure was used:

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[1] The system capacity factor includes a 10 percent reserve margin. It is computed as:

$$CF = \frac{E}{8.76 \times (P \times 1.1)}$$

Where: E = Energy load
P = Peak load

1. A base system consisting of all existing plants was established. The expected system operating costs were computed for 45 stream-flow sequences under balanced load and resource conditions. System operating costs include water rental fees, fuel costs for Burrard costs of purchases, and credits for estimated export sales.

2. Using the same procedure, the cost of system operation was computed for an alternative system consisting of the above plants plus a hypothetical plant capable of providing 100 GW.h/a of energy in all water conditions except low stream-flow years, when it produces no energy.

3. The marginal value of the secondary energy was then computed as a difference between the estimated system operating costs for the base case and for the sequence with the additional secondary energy, divided by the added secondary energy.

4. The marginal value of secondary energy is based on incremental changes on existing resources and thus is independent of discount rates.

   The average value of secondary energy at the load centre is:

   With Taxes : 2.0 ¢/kw.h

   Without Taxes: 1.9 ¢/kw.h

Table 1

LONG TERM LOAD CENTRE CAPACITY AND ENERGY VALUES
1989 DOLLARS

		WITH TAXES	WITHOUT TAXES
Firm Capacity	$/kW/a	24.4	20.4
	¢/kW.h	0.5	0.4
Firm Energy	¢/kW.h	4.5	4.2
Value of Electricity*1	¢/kW.h	5.0	4.6
Secondary Energy	¢/kW.h	2.0	1.9

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*1 Value shown is the value of 1 kW of firm capacity plus the amount of firm energy that 1 kW would produce if operated at system load factor.

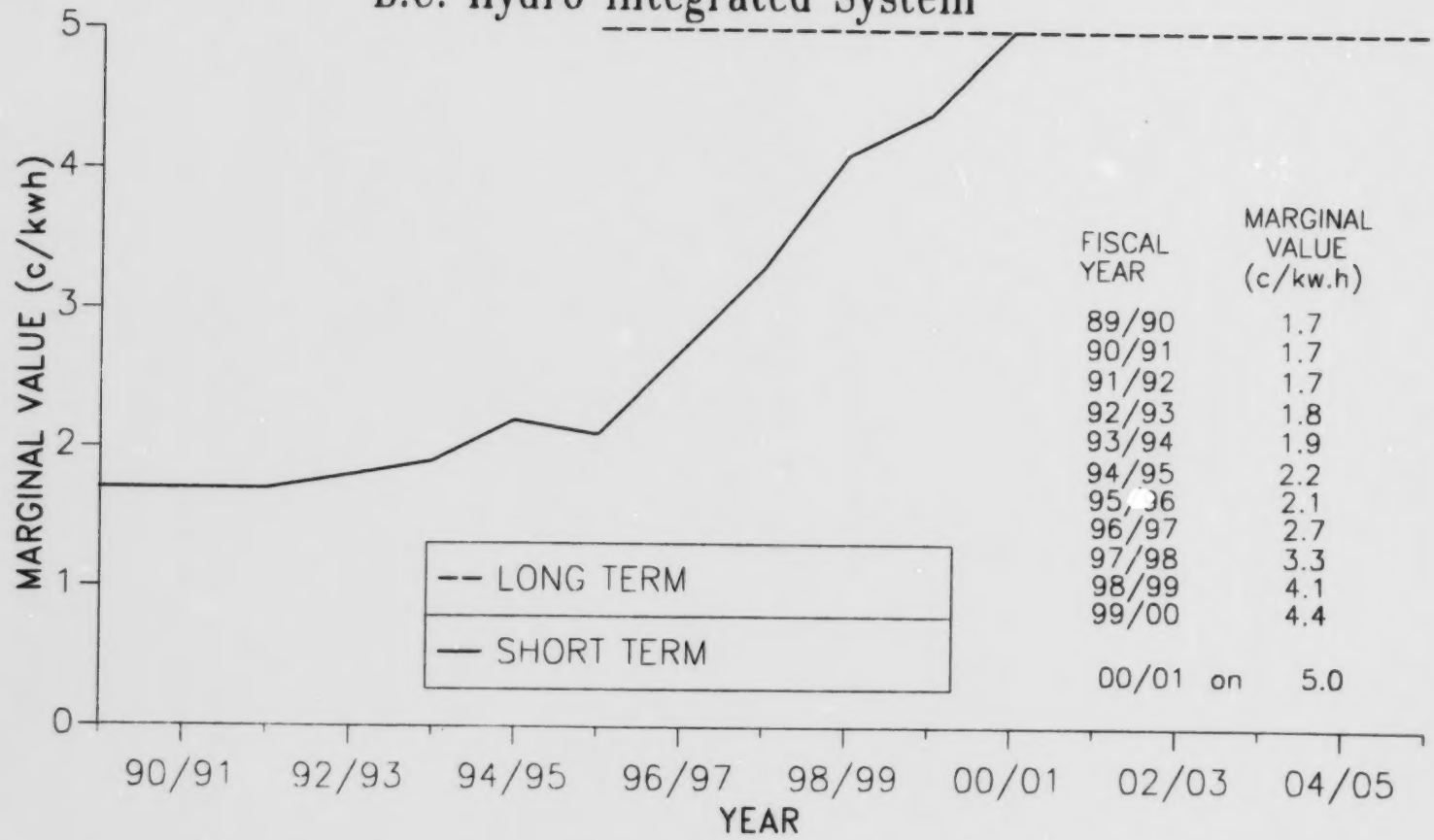
Example: Assuming each project is designed to operate near the system capacity factor of 58 percent each kW of capacity will generate:

$$1 \times 8760 \times 0.58 = 5080.8 \text{ kW.h/a}$$

A capacity cost of $24.4/kW/a is therefore equivalent to an energy cost of:

$$(24.4 \times 100)/(8760 \times 0.58) = 0.5 \text{ c/kW.h}$$

TABLE 1
MARGINAL VALUE OF ELECTRICITY *
B.C. Hydro Integrated System



FISCAL YEAR	MARGINAL VALUE (c/kw.h)
89/90	1.7
90/91	1.7
91/92	1.7
92/93	1.8
93/94	1.9
94/95	2.2
95/96	2.1
96/97	2.7
97/98	3.3
98/99	4.1
99/00	4.4
00/01 on	5.0

* Energy and capacity in 1989 dollars

APPENDIX I
Project Unit Costs

Appendix I

PROJECT UNIT COSTS

The long term unit cost of a project is the expected average cost (in current years constant dollars) of energy produced by the project over its lifetime. As such it is a function of the discount rate, the project costs, energy capability, peak capacity and operating life. B.C.Hydro uses project unit costs as a relative index of the projects economic attractiveness as well as to estimate the value of electricity to the B.C. Hydro system.

Table I-1 shows the unit costs of the projects that form the inventory of possible future generation developments in British Columbia. Information is provided for discount rates between 5 and 10 percent with and without taxes. This table provides costs of energy and capacity delivered to B.C. Hydro's 500 kV grid. Transmission loss data for specific projects are provided in Table I-2.

Computation of Unit Costs

There are several different ways to calculate unit energy costs. Two methods are described below. While these methods may appear different, they are mathematically equivalent.

a. Annual Cost Method:

Computation of the unit energy cost follows the four steps outlined below.

i) Compute the total capital cost by accumulating all annual construction costs, overheads and interest during construction to the project in-service date.
Table I-3 provides the basis for estimating operating costs and Table I-4 provides corporate overhead rates based on the capital costs of projects under consideration.

ii) Compute the annual interest and depreciation payments over the project's operating life from the total capital cost for the assumed discount rate. Sinking fund depreciation is used to ensure that the total interest and depreciation cost is a series of uniform annual payments over the entire life of the project.[2]

iii) Compute the total annual cost as the sum of the above interest and depreciation costs plus the estimated annual operating costs.

iv) Divide the total annual cost by the project's firm energy capability to obtain the unit energy cost.

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[2]See the glossary for definitions of construction costs and operating costs.

The above methodology is satisfactory for most problems. However, it can be difficult to apply when the operating costs or energy capability varies over the project's lifetime. In these cases, the unit energy cost varies with time and must be converted into an equivalent uniform series. While this is not difficult, it is often easier to use the alternative method below.

b. Present Value Method

In this method, the unit cost is computed by dividing the present value of all project costs by the present value of the project's energy capability.

This explanation always raises the question of "what is the meaning of the present value of energy?". The answer is that we are actually computing the present value of revenue from the sale of the project's energy. If the energy is sold at the project's unit cost the present value of the revenues should equal the present value of the project's costs.

This can best be shown mathematically as follows:

Project Revenue = Energy * Assumed Selling Price per unit of energy
= Energy * Unit Cost

And:

Present Value (Project Revenue) = Present Value (Project Costs)
Present Value (Energy * Unit Cost) = Present Value (Project Costs)

Since the project unit energy cost is a constant and a present value is a form of summation over time, the unit cost can be taken outside the bracket, as follows:

Unit Cost * P.V. (Energy) = P.V. (Project cost)

And:

Unit Cost = P.V. (Project Cost) / P.V. (Energy)

TABLE I-1
PROJECT UNIT COSTS
(1989 mills/kW.h)

	WITH TAXES					NO TAXES				
HYDRO PROJECTS*[1]	5%	6%	7%	8%	10%	5%	6%	7%	8%	10%
Peace Site C	30.9	35.9	41.4	47.1	59.9	25.8	31.0	36.4	42.2	48.4
(with Williston-Kelly Lake Transm)	33.1	38.3	44.1	50.3	63.6	28.0	33.4	39.2	45.3	51.8
Keenleyside 240 mW	32.3	37.5	42.9	48.6	60.9	27.3	32.4	37.9	43.6	49.6
Murphy Creek(after KNL 240)	38.9	45.8	53.3	61.4	79.2	34.1	41.1	48.5	56.6	65.2
Keenleyside 240/Murphy	35.3	41.1	47.1	53.7	67.5	30.5	36.2	42.3	48.8	55.5
Keenleyside 180 mW	32.0	37.2	42.5	48.2	60.5	27.2	32.3	37.7	43.4	49.4
Murphy Creek(after KNL 180)	37.6	44.3	51.6	59.3	76.5	32.9	39.6	46.8	54.6	62.9
Keenleyside 180/Murphy	34.7	40.3	46.3	52.7	66.4	29.8	35.5	41.6	48.0	54.6
Murphy Creek(alone)	33.6	39.2	45.2	51.6	65.1	29.0	34.5	40.5	46.8	53.4
Stikine-Iskut	44.6	52.0	60.0	68.7	88.3	34.2	41.4	49.2	57.9	67.2
Liard (Devils Gorge/Hell Gate)	41.4	47.5	54.2	61.4	77.8	30.7	36.8	43.4	50.6	58.4
Liard (DGOR/HLGT/BCRL)	46.7	53.6	61.0	69.0	86.8	35.2	41.9	49.4	57.3	65.8
Homathko(Waddington/Mosley/Nude)	50.8	58.1	65.7	73.9	91.5	39.0	46.1	53.9	62.1	70.6
Homathko(Waddington/Mosely)	49.6	56.7	64.4	72.3	89.8	37.7	44.8	52.4	60.5	68.9
Brilliant	31.8	36.6	41.9	47.3	58.7	26.8	31.7	36.9	42.3	47.9
Waneta	29.0	33.3	37.9	42.6	52.7	23.3	27.6	32.1	37.0	41.9
Lower Canyon	35.8	40.6	45.9	51.3	63.0	25.6	30.6	35.7	41.2	46.9
Elaho	41.6	47.4	53.6	60.0	73.8	31.0	36.8	42.8	49.4	56.1
Border	37.3	43.6	50.4	57.6	73.3	32.6	38.9	45.7	52.9	60.6
THERMAL PROJECTS										
Hat Creek 2000 mW	32.6	35.8	39.5	43.4	51.9	29.3	32.6	36.1	39.9	44.0
Hat Creek 720 mW	37.3	40.3	43.6	47.1	55.0	33.5	36.5	39.8	43.4	47.1
East Kootenay Thermal	51.1	55.4	60.1	65.0	75.9	45.7	50.0	54.6	59.5	64.8
Gas Turbines	69.7	69.8	70.1	70.5	71.4	68.5	68.7	68.9	69.3	69.7

[1]Unit costs for hydro-electric projects are based on average energy capability.

Table I-2

Transmission Cost and Loss Data

Plant	Capacity MW	C.F. (%)	Plant Losses % Peak Output	Plant Losses % Energy Output	Incremental Losses % Peak Output	Incremental Losses % Energy Output	Incremental T/M Costs ($/KW)
Plant							
Kemano Compltn.	520	66+	-4.4	-3.4	9.6	7.3	9.2
Keenlyside	180	48*	2.1	1.5	3.4	2.8	14.1
Keenlyside	240	49*	2.6	2.2	5.0	3.8	14.3
Murphy	275	75*	1.9	1.6	3.4	2.5	14.1
Keenly + Murphy	455	64*	2.1	1.5	3.8	2.6	14.9
Site C	900	60+	6.4	4.6	10.0	6.5	11.9
Stikine-Iskut	2900	61+	4.0	2.9	11.0	8.0	16.7
Hat Creek	720	67*	-1.1	-0.61	-0.39	-0.23	0
Hat Creek	2000	67*	-1.0	-0.58	-0.38	-0.22	0
Homathko	900	56+	0.50	0.35	2.6	1.8	0
East Kootenay	600	67*	5.3	4.1	10.0	7.7	15.2
Liard	4318	67+	4.4	3.4	9.7	7.5	16.4
Liard	3190	66+	3.2	2.5	6.9	5.3	14.8
Cutoff Mountain	1290	61+	3.6	2.6	7.8	5.6	8.8
Lower Canyon	360	62+	8.6	6.3	13.9	10.1	6.5
Border	250	74*	1.7	1.3	3.0	2.0	14.0
Elaho	343	70*	1.3	1.3	4.1	3.4	1.1

Footnotes

Peak Loss (%) = (100)(Peak Loss Mw)/(Plant Capacity MW)

+ For these plants, the energy losses were determined as follows:

$$\text{Load Loss Factor (LLF)} = .7(CF)(CF) + .3(CF)$$

$$\text{Energy Loss (Mw.h)} = (\text{Peak Loss MW})(LLF)(8760)$$

$$\text{Energy Loss (\%)} = \frac{(100)(\text{Peak Loss MW})(LLF)(8760)}{(CF)(\text{Plant Capacity MW})(8760)}$$

$$\text{Energy Loss (\%)} = (\text{Peak Loss \%})(LLF)/(CF)$$

* The energy losses for these plants do not depend solely on the capacity factor of the plant. They also depend on the loading factor of the transmission, as affected by other generation in the area.

SOURCE: SYSTEM PLANNING, MAY 1989

TABLE I-3

BASIS FOR ESTIMATING OPERATING COSTS
(October 1988 dollars)

	Hydro	Gas/Oil Thermal	Coal-Fired Thermal	Gas Turbine	Transmission Stations	Transmission Wood Pole	Transmission Steel
Fixed Annual Charges (percent of uninflated Total construction cost)*1							
Operation and Maintenance	0.45	1.80	0.86	1.47	1.2	1.2	0.6
Administration and General Expense	incl.	0.45	incl.	0.13	incl.	incl.	incl.
Insurance	0.03	0.03	0.02	0.03	incl.	incl.	incl.
Grants and Taxes	1.33	1.33	1.33	1.33	0	0.7	1.3
Interim Replacement	incl.	0.35	incl.	incl.	incl.	incl.	incl.
TOTAL	1.81	3.96	2.21	2.96	1.20	1.90	1.90
Variable Annual Charges*2 (mills/kW.h, 1988)	3.99*3	0.667	0.131	incl.	--	--	--
Assumed Plant Life (years)	70	35	35	30	30	30	45

Notes: *1 Total construction cost excludes Corporate Overhead and Interest during Construction.

*2 Variable annual charges are subject to annual escalation. Fuel costs are additional to variable charges and are to be determined separately for each project.

*3 Energy portion of Annual Water Rental Allowance. An additional capacity charge of 2.85 $/kW is also applicable to hydro projects.

TABLE I-4

CORPORATE OVERHEAD RATES - February 1989

O/H RATE = .12 - .068 ARCTAN LOG (Project Total Uninflated Direct Cost/1,000,000)

TOTAL UNINFLATED DIRECT COST RANGE (k$)		OVERHEAD RATE (%)
1	10	20
11	38	19
39	89	18
90	166	17
167	271	16
272	411	15
412	596	14
597	843	13
844	1,184	12
1,185	1,675	11
1,676	2,427	10
2,428	3,677	9
3,678	6,010	8
6,011	11,168	7
11,169	26,056	6
26,057	95,309	5
95,310	1,022,279	4
1,022,280	15,000,000	3

SOURCE: Plant Accounting, Feb 1989

APPENDIX II
COST - BENEFIT ANALYSIS: EXAMPLE

EXAMPLE 1

Consider an addition of a generating unit to an existing dam at which no power facilities were originally incorporated.

DATA	
Installed Capacity	25 MW
Average Annual Energy	105 GW.h
Firm Annual Energy	76 GW.h
Generation Construction Cost (1987 $)	42,600,000
Transmission construction Cost (1987 $)	8,900,000
Duration Of Construction	3 1/2 years
Physical Lifetime	70 years

For this example cost-benefit analysis is computed using two methods.

Method 1: Calculation of Equivalent Uniform Annual Costs and Benefits.

Computation is provided for 6 and 8 percent net discount rates. Refer to Tables II-1, II-2 and II-3.

For a 6 percent discount rate equivalent uniform benefits, over the projects life time, are estimated at $ 4,143,000, while the annual costs are computed to be $ 5,445.500 showing that this project is not economical.

Method 2: Cash-flow computation over projects life time.

Refer to Table II-4. Computation is provided for a 6 percent and an 8 percent discount rates.

Example 1 - Method 1
(Calculation of Equivalent Uniform Annual Costs and Benefits)

TABLE II-1

EXAMPLE 1
(Method 1)

EXAMPLE OF EVALUATION OF A SMALL DESIGN CHANGE ASSUMING ALL TAXES ARE CONSIDERED
(Calculation of Equivalent Uniform Annual Costs and Benefits)

Problem formulation

Consider an addition of a generating unit at an existing dam at which no power facilities were originally incorporated.

DATA

Installed capacity	25 mW
Average Energy	105 gW.h
Firm annual energy	76 gW.h
Generation construction cost	42,600,000 (1987$)
Transmision construction cost	8,900,000 (1987$)
Proposed in-service date	1995 year
Duration of construction	3.5 years
Physical lifetime	70 years

BENEFITS:

		@ 6% Equivalent Uniform Value*	@ 6% Annual Benefits (k$)	@ 8% Equivalent Uniform Value	@ 8% Annual Benefits (k$)
Firm Capacity	25 mW	20.2 $/kw/a	505.0	19.4 $/kw/a	485.0
Firm Energy	76 gW.h	4.1 c/kW.h	3,116.0	4.1 c/kW.h	3,116.0
Secondary energy	29 gW.h	1.8 c/kW.h	522.0	1.8 c/kW.h	522.0
			4,143.0		4,123.0

COSTS:

	Costs	@ 6% Annual Charges**	@ 6% Annual Cost (k$)	@ 8% Annual Charges	@ 8% Annual Cost (k$)
Generation	46,100,000 (1989$)	0.088 (8.8%)	4,056.8	0.115 (11.5%)	5,301.5
Transmission	9,600,000 (1989$)	0.092 (9.2%)	883.2	0.114 (11.4%)	1,094.4
Water rental fees		0.4 c/kW.h	430.5	0.4 c/kW.h	430.5
Capacity fee		3.0 $/kW/a	75.0	3.0 $/kW/a	75.0
			5,445.5		6,901.4

	@6%	@8%
Unit Cost (c/kw.h) (Annual Cost/Average Energy)	5.2	6.6

* Refer to Table II-2
** Refer to Table II-3

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(ex1a)

TABLE II-2

COMPUTATION OF UNIFORM VALUES FOR CAPACITY AND ENERGY FOR EXAMPLE 1

	YEAR	Capacity ($/kW/a)	Firm Energy (c/kw.h)	Secondary Energy (c/kw.h)
1	95/96	6.0	2.1	1.1
2	96/97	6.0	2.7	1.3
3	97/98	6.0	3.3	1.5
4	98/99	6.0	4.1	1.7
5	99/00	24.4	4.4	1.9
6	00/01	24.4	4.5	2.0
7	01/02	24.4	4.5	2.0
8	02/03	24.4	4.5	2.0
9	03/04	24.4	4.5	2.0
10	04/05	24.4	4.5	2.0
11	05/06	24.4	4.5	2.0
12	06/07	24.4	4.5	2.0
13	07/08	24.4	4.5	2.0
14	08/09	24.4	4.5	2.0
15	09/10	24.4	4.5	2.0
16	10/11	24.4	4.5	2.0
17	11/12	24.4	4.5	2.0
18	12/13	24.4	4.5	2.0
19	13/14	24.4	4.5	2.0
20	14/15	24.4	4.5	2.0
21	15/16	24.4	4.5	2.0
22	16/17	24.4	4.5	2.0
23	17/18	24.4	4.5	2.0
24	18/19	24.4	4.5	2.0
25	19/20	24.4	4.5	2.0
26	20/21	24.4	4.5	2.0
27	21/22	24.4	4.5	2.0
28	22/23	24.4	4.5	2.0
29	23/24	24.4	4.5	2.0
30	24/25	24.4	4.5	2.0
31	25/26	24.4	4.5	2.0
32	26/27	24.4	4.5	2.0
33	27/28	24.4	4.5	2.0
34	28/29	24.4	4.5	2.0
35	29/30	24.4	4.5	2.0
36	30/31	24.4	4.5	2.0
37	31/32	24.4	4.5	2.0
38	32/33	24.4	4.5	2.0
39	33/34	24.4	4.5	2.0
40	34/35	24.4	4.5	2.0
41	35/36	24.4	4.5	2.0
42	36/37	24.4	4.5	2.0
43	37/38	24.4	4.5	2.0
44	38/39	24.4	4.5	2.0
45	39/40	24.4	4.5	2.0
46	40/41	24.4	4.5	2.0
47	41/42	24.4	4.5	2.0
48	42/43	24.4	4.5	2.0
49	43/44	24.4	4.5	2.0
50	44/45	24.4	4.5	2.0
51	45/46	24.4	4.5	2.0

52	46/47	24.4	4.5	2.0			
53	47/48	24.4	4.5	2.0			
54	48/49	24.4	4.5	2.0			
55	49/50	24.4	4.5	2.0			
56	50/51	24.4	4.5	2.0			
57	51/52	24.4	4.5	2.0			
58	52/53	24.4	4.5	2.0			
59	53/54	24.4	4.5	2.0			
60	54/55	24.4	4.5	2.0			
61	55/56	24.4	4.5	2.0			
62	56/57	24.4	4.5	2.0			
63	57/58	24.4	4.5	2.0			
64	58/59	24.4	4.5	2.0			
65	59/60	24.4	4.5	2.0			
66	60/61	24.4	4.5	2.0			
67	61/62	24.4	4.5	2.0			
68	62/63	24.4	4.5	2.0			
69	63/64	24.4	4.5	2.0			
70	64/65	24.4	4.5	2.0			
Discount Rate:		0.06	0.06	0.06	0.08	0.08	0.08
Total P.V.:		336.0	68.5	30.6	242.7	50.9	22.8
Project life(years)		70	70	70	70	70	70.0
Capital Recovery Factor		0.06	0.06	0.06	0.08	0.08	0.08
Uniform Value (P.V./Capital Recovery factor)		20.2	4.1	1.8	19.4	4.1	1.8

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(ex1b)

TABLE II-3
ANNUAL COST FACTOR CALCULATIONS FOR EXAMPLE 1

Discount Rate:	6%		8%	
CAPITAL COSTS	Hydro	Trans.	Hydro	Transm.
Total uninflated construction cost	100.00	100.00	100.00	100.00
Corporate overhead (Table I-4)	5.00	7.00	5.00	7.00
	105.00	107.00	105.00	107.00
Interest During Construction *				
Hydro: Average 1.5 Years	9.45	6.42	15.75	8.56
Transmission: Average 1 years				
(Assumes a 3.5 year construction)				
Total Uninflated Capital Cost	114.45	113.42	120.75	115.56
ANNUAL COSTS(Table I-3)				
Interest Charges	6.87	6.81	9.66	9.24
Depreciation (sinking fund) **				
Hydro: 70 years	0.12	0.53	0.04	0.30
Transmission: 45 years				
Operating and maintenance (no taxes)				
Hydro: 0.48% of 100	0.48	0.60	0.48	0.60
Transmission 0.6% of 100				
Grants, taxes (no water rental fees)				
Hydro: 1.33% of 100	1.33	1.30	1.33	1.30
Transmission: 1.30% of 100				
TOTAL ANNUAL CHARGES WITHOUT TAXES	7.47 %	7.94 %	10.18 %	10.14 %
TOTAL ANNUAL CHARGES WITH TAXES	8.80 %	9.24 %	11.51 %	11.44 %
Variable Charges(1989 $)				
Water rental fees: c/kW.h	0.41	0.00	0.41	0.00
Capacity charges : $/kW	3.00	0.00	3.00	0.00

* Interest During Construction: example @ 6%
Hydroelectric (average): 1.5 Years @ 6%=9% of 105 is 9.45
Transmission (average): 1 Years @ 6%=6% of 107 is 6.42

** Sinking fund example @ 6%:
Hydroelectric: int=6%, n=70 years, PV=1
PMT= -0.06103 ; i=6% Depreciation=0.103%
0.103% of 114.5=0.12
Transmission: int=6%, n=45 years, PV=1
PMT= -0.06470 ; i=6% Depreciation=0.470%
0.470% of 113.42=0.53

Example 1 - Method 2
(Cash - Flow Computation over Project's Life Time)

08/30/89
ex1c

TABLE II-4
EXAMPLE 1
(Method 2)

EXAMPLE OF EVALUATION OF A SMALL DESIGN CHANGE FOR A 6% AND 8% DISCOUNT RATES
Cash-flow calculation over projects life-time

		BENEFITS									COSTS			
		FIRM CAPACITY			FIRM ENERGY		SECONDARY ENERGY				GENERATION*		TRANSMISSION*	
	YEAR	(MW)	Unit Value $/kW/a	Value (k$)	GW.h/a	Unit Value c/kW.h	Value (k$)	(GW.	Unit Value c/kW.h	Value k$	AVERAGE ENERGY GW.h/a	CAPITAL COST (k$)	OPERATING & MAINT. (k$)	CAPITAL COST (k$)	OPERATIN & MAINT. (k$)
	89/90	0	6.0	0.0	0	1.7	0.0	0.0	1.1	0.0	0	0.0	0.0	0.0	0.0
	90/91	0	6.0	0.0	0	1.7	0.0	0.0	1.1	0.0	0	0.0	0.0	0.0	0.0
	91/92	0	6.0	0.0	0	1.7	0.0	0.0	1.1	0.0	0	15,000.0	0.0	3,200.0	0.0
	92/93	0	6.0	0.0	0	1.8	0.0	0.0	1.1	0.0	0	15,000.0	0.0	3,200.0	0.0
	93/94	0	6.0	0.0	0	1.9	0.0	0.0	1.1	0.0	0	15,000.0	0.0	3,200.0	0.0
	94/95	0	6.0	0.0	0	2.2	0.0	0.0	1.1	0.0	0	3,405.0	0.0	672.0	0.0
1	95/96	25	6.0	150.0	76	2.1	1,596.0	29.0	1.1	319.0	105	0.0	1,339.9	0.0	182.4
2	96/97	25	6.0	150.0	76	2.7	2,052.0	29.0	1.3	377.0	105	0.0	1,339.9	0.0	182.4
3	97/98	25	6.0	150.0	76	3.3	2,508.0	29.0	1.5	435.0	105	0.0	1,339.9	0.0	182.4
4	98/99	25	6.0	150.0	76	4.1	3,116.0	29.0	1.7	493.0	105	0.0	1,339.9	0.0	182.4
5	99/00	25	24.4	610.0	76	4.4	3,344.0	29.0	1.9	551.0	105	0.0	1,339.9	0.0	182.4
6	00/01	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
7	01/02	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
8	02/03	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
9	03/04	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
10	04/05	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
11	05/06	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
12	06/07	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
13	07/08	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
14	08/09	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
15	09/10	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
16	10/11	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
17	11/12	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
18	12/13	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
19	13/14	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
20	14/15	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
21	15/16	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
22	16/17	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
23	17/18	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
24	18/19	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
25	19/20	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
26	20/21	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
27	21/22	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
28	22/23	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
29	23/24	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
30	24/25	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
31	25/26	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
32	26/27	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
33	27/28	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
34	28/29	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
35	29/30	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
36	30/31	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
37	31/32	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4

38	32/33	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
39	33/34	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
40	34/35	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
41	35/36	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
42	36/37	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
43	37/38	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	3,200.0	182.4
44	38/39	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	3,200.0	182.4
45	39/40	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	3,200.0	182.4
46	40/41	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	672.0	182.4
47	41/42	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
48	42/43	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
49	43/44	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
50	44/45	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
51	45/46	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
52	46/47	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
53	47/48	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
54	48/49	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
55	49/50	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
56	50/51	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
57	51/52	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
58	52/53	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
59	53/54	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
60	54/55	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
61	55/56	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
62	56/57	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
63	57/58	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
64	58/59	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
65	59/60	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
66	60/61	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
67	61/62	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
68	62/63	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
69	63/64	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
70	64/65	25	24.4	610.0	76	4.5	3,420.0	29.0	2.0	580.0	105	0.0	1,339.9	0.0	182.4
Discount Rate				0.06			0.06			0.06	0.06	0.06	0.06	0.06	0.06
Total P.V.:				5,922.1			36,681.6			6,248.6	1,213	38,085.0	15,476.5	8,673.9	2,106.8
Discount Rate				0.08			0.08			0.08	0.08	0.08	0.08	0.08	0.08
Total P.V.:				3,823.0			24,383.5			4,160.6	823.31	35,287.4	10,506.3	7,728.5	1,430.2

FOR 6% DISCOUNT RATE
Total Benefits (k$): 48,852.3
Total Costs (64,342.1
Unit Cost (c/kW.h) 5.3 (Present worth of total cost/Present worth of average energy)

FOR 8% DISCOUNT RATE
Total Benefits (k$): 32,367.1
Total Costs (54,952.4
Unit Cost (c/kW.h) 6.7 (Present worth of total cost/Present worth of average energy)

Capital Cost in 1989$ = 46,100k$ + 5% overhead costs. Cash flow distribution assumed
(For overhead costs see Table I-4)
Annual Operating & Maintenance = (1.81)% of 46,100 k$ + 0.41 c/kw.h * 105gW.h + 3$/kW/a * 25mW
(Table I-3)
**TRANSMISSION
Capital Cost in 1989$ = 9,600k$ + 7% overhead costs. Cash flow distribution assumed
Annual Operating & Maintenance = (1.9)% of 9,600 k$ (Table I-3)

GLOSSARY

1. Firm Energy - The average annual energy that could be assured during a recurrence of the worst sustained coincident critical drought period experienced in the B.C. Hydro system between 1940 and 1985. For the present system, this corresponds to the historical stream flow period from October 1940 to April 1945.

2. Average Energy - is the average annual generation of each project during a repetition of the 45-year reference streamflow record from 1940 to 1985.

3. Secondary Energy - is equal to the difference between average energy and firm energy of hydroelectric projects.

4. Dependable Capacity - the output level which the electric system can reliably sustain at the time of peak load. For hydro projects with storage reservoirs or fluctuating forebay levels, dependable capacity is calculated using reservoir drawdown levels that would be reached at the end of January 1945 during a repetition of the critical period stream flows.

5. Load Centre - as used in these guidelines, is defined as the B.C. Hydro mainland 500 kV transmission grid interconnections at existing substations at Kelly Lake and Nicola. The load centre value of electricity does not include the costs of grid transmission south of these locations, or costs of secondary transmission and distribution. These additional costs are assumed to be common to all major generation projects and thus will not influence cost-benefit comparisons.

6. Construction costs - These costs include all direct project costs as well as engineering and contingency allowances. Corporate overheads, normally estimated as a fraction of the construction cost estimate, are also included.

7. Operating Costs - These include such items as fuel, water licence fees, operations and maintenance, interim replacement and taxes or grants in-lieu of taxes. Usually these are calculated as a percentage of total construction costs of various types of plant as shown in Table I-3. Fuel costs and water licence fees are estimated from the expected energy generation from the resource.

8. Project Unit Energy Costs - Unit energy costs can reflect either a project's average usable energy or its firm energy capability. The interpretation of unit costs based on theses two values is as follows:

   a. Average Usable Energy - This unit cost reflects the average cost of energy generated by the project over its lifetime. These values give a fair representation of relative economics of based-loaded projects. However they can be misleading when used to compare projects which have higher incremental costs.

   For example, during periods of surplus it may be economic to reduce the output of a thermal project to reduce its fuel costs. However, this would result in less energy generation over the thermal project's life. In this

case, use of average energy generation to compute the unit cost will make the thermal project appear less economic than another similar project which did not have the flexibility to reduce its output. This can lead to obvious discrepancies in which a more highly constrained project appears to be more economic than a flexible one.

b. Energy Capability - In this case the unit energy cost reflects the relative impact of the project on the economics of B.C. Hydro's system operation. These unit costs will be more representative for projects which have the flexibility to reduce generation as described above. However, these costs may not be representative of the average cost of energy ultimately produced by the project.